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Electric Rates and Boiler Fuel Choice

Radian Corp.
Austin, TX

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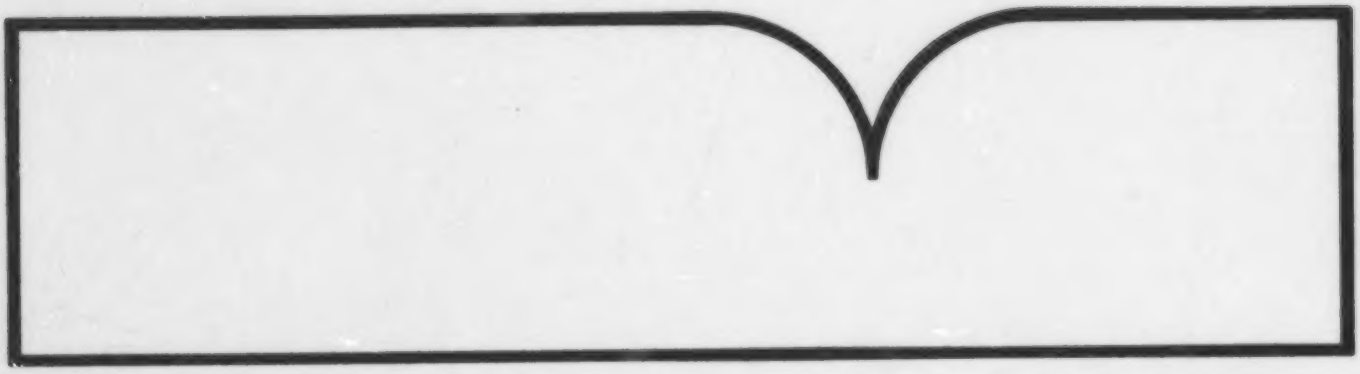

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ABSTRACT

This study was undertaken in response to an EPA/IERL-RTP request to examine in a "quick look" fashion the economic tradeoffs of using purchased utility electricity as an alternative to on-site combustion of fossil fuels for industrial steam generation. Specifically, the impacts of marginal or incremental cost pricing of electricity and increasingly stringent industrial boiler emission controls were examined for a 44 MW_t (150×10^6 Btu/hr heat input) industrial boiler. Data were compared to determine if electricity, despite its lower overall thermal efficiency, could be economically competitive with direct firing of fossil fuels in this size boiler.

Marginal (or incremental) cost pricing of electricity has been a factor in rate design in the U.S. for the last 50 years. Marginal costs are designed to reflect the full social costs of resources needed to deliver additional (or incremental) electricity. In this study, the concept of marginal cost pricing is extended to industrial steam generation.

This study was not designed to be either a definitive analysis of marginal cost pricing techniques or a comprehensive overview of the impacts of marginal cost pricing on industrial energy sources. The number of variables that need to be taken into account in estimating marginal industrial steam costs is extremely large. Only a few of these were taken into account in this evaluation. Further, a number of simplifying assumptions had to be made in order to conduct the comparisons within the resource limitations of the study. Several of these simplifications tended to reduce the hypothetical marginal cost of electricity while increasing the estimated marginal cost of on-site fossil fuel combustion. Despite this, the results of this study show that, for the two cases evaluated, electricity would not be competitive with direct firing of fossil fuels as an industrial boiler energy source if both electricity and fossil fuels were priced at marginal cost. These results are not applicable to all situations where selection of an industrial boiler energy source has to be made. These results are valid only for the cases described and for the assumptions made.

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CONTENTS

Abstract iii
List of Tables vi
Acknowledgements viii

1. Introduction and Conclusions. 1
2. Estimates of Marginal Costs of Electricity and the User Costs of Industrial Steam Generation. 5
3. Analysis of Impacts of Alternative Utility Rate Structures on Industrial Selection of a Boiler Energy Source 19

Limitations of This Study. 31
References 33
Glossary 34
Appendices
A. Emissions control levels for industrial boilers 35
B. Operating characteristics and annualized costs of 44 MW_t industrial boilers. 36

TABLES

Number		Page
1	Revised Capitalization, Current Basis, Utility A	8
2	Determination of the Current Valuation of Investment, Utility A	10
3	Determination of Depreciation Costs on a Current Basis, Utility A	11
4	Current Costs of Fuel, Utility A	11
5	Determination of the Increase in Income Taxes, Current Cost Basis, Utility A	12
6	Adjusted Cost of Service, Current Cost Basis, Utility A	14
7	Adjusted Cost of Service, Current Cost Basis, Utility B	15
8	Annualized Costs of Producing Steam Given a 44 MW_t Boiler, Four Boiler Fuels, and Three Emissions Control Levels (May, 1980 Dollars)	18
9	Utility A Rates for an Industrial User	20
10	Annual Electricity Cost of a 44 MW_t Electric Boiler for 4,818 Hours (Peak Demand = 44,000 KW), Utility A (1980 Dollars) .	20
11	Utility B Rates for Large Industrial Users	22
12	Annual Electricity Cost of a 44 MW_t Electric Boiler for 4,818 Hours (Peak Demand = 44,000 KW), Utility B (1980 Dollars) .	23
13	Total Annualized Costs of Producing Steam from a 44 MW_t Electric Boiler Given Existing Electricity Rates (1980 Dollars).	24
14	Costs ($/10^6 Btu) of Producing Steam from Fossil Fuels and Electricity Using Existing Electricity Rates (1980 Dollars) of Utility A and Utility B.	25
15	Cases Where Electricity (Present Rate Structure) May be Economically Attractive for the Hypothetical Boiler Studied . . .	27

TABLES (CONT.)

Number		Page
16	Total Annualized Costs and Costs ($/10^6 Btu) of Producing Steam from a 44 MW_t Electric Boiler Given Electricity Rates that Reflect Marginal Cost Pricing (1980 Dollars) . .	28
17	Costs ($/10^6 Btu) of Producing Steam from Fossil Fuels and Electricity Given Electricity Rates of Utility A and Utility B that Reflect Marginal Cost Pricing (1980 Dollars).	30
A-1	Approximate Emission Rates for Three Levels of Emission Controls.	34
B-1	Operating Characteristics and Annualized Costs of a 44 MW_t Industrial Boiler Fired with Natural Gas.	36
B-2	Operating Characteristics and Annualized Costs of a 44 MW_t Industrial Boiler Fired with Residual Oil (3.0% Sulfur) . .	37
B-3	Operating Characteristics and Annualized Costs of a 44 MW_t Industrial Boiler Fired with Eastern Coal (3.5% Sulfur) . .	39
B-4	Operating Characteristics and Annualized Costs of a 44 MW_t Industrial Boiler Fired with Western Subbituminous Coal (0.6% Sulfur).	40
B-5	Operating Characteristics, Capital Investment, and Annualized Costs of a 44 MW_t Electric Boiler.	41

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SECTION 1
INTRODUCTION AND CONCLUSIONS

Background

In the industrial sector, steam is generated primarily with the combustion of fossil fuels. The objective of this study was to examine the economic tradeoffs associated with industrial fossil fuel combustion and the use of electricity for steam generation given existing (1980) electricity rates, hypothetical rates reflecting marginal costs, unregulated 1980 market prices of four fossil fuels, and several levels of emissions controls for the fossil fuel-fired boilers. The basic issue addressed was the economic tradeoffs associated with selecting an industrial boiler energy source if all energy sources (oil, gas, coal, and purchased utility electricity) were priced at hypothetical levels reflecting their marginal costs.

A number of variables influence the selection of boiler energy sources. Two factors which were considered in this study are 1) the impact of electricity rate structures which more closely reflect marginal costs and which, as a result, are higher than existing, regulated rates; and 2) increased costs resulting from application of emission controls to fossil fuel-fired boilers to meet environmental regulations. While use of electricity eliminates costs associated with emission controls for industrial boilers, the much higher electricity costs (compared with fossil fuels on a dollar per million Btu basis) significantly limits the viability of this alternative.

Theoretically, marginal or incremental cost pricing is defined to mean pricing all units of output at a level equal to the marginal cost of the last unit of output produced.[1] The economic justification for marginal cost

[1]There is a need for a clear practical definition of marginal costs and for a clear procedure for ratemaking based on marginal cost (Electric Utility Rate Design Study, Nov. 1977, p.3). Marginal cost pricing of electricity issues are not addressed in this study because they are beyond the scope of this work.

pricing is the efficient use of society's scarce resources. Prices set on the basis of marginal costs reflect the full costs to society of the resources used to produce the goods or services. If prices are less than marginal costs, resources are used inefficiently and society has to bear the cost of inefficient rates of resource utilization. To the extent that electric rates reflect marginal costs, rates provide signals to customers concerning the amount of consumption that is consistent with the regulatory objective of economically efficient use of resources, especially those that are energy-related (Electric Utility Rate Design Study, November 1977, p. 5). Marginal cost pricing of electricity was first used in the design of promotional rates in the 1920's. Promotional rates, designed to capture specific markets, were justified by the industry as capitalizing on the economies of scale in electricity generation and producing lower costs to all customers (National Economic Research Associates, February 1977, p. viii). The gradual downward trend in electricity rates was ended in the late 1960's and early 1970's by rapidly increasing fuel costs and capital costs. The current problems of utility revenue erosion have generated considerable interest in developing rate structures that could curb uneconomic growth of the peak. During the last ten years, a version of marginal cost based on long-run incremental cost has been introduced into various rate proceedings for the purposes of providing economic insight into efficient rate design (ibid, p. ii).

Methodology

This study is neither a definitive analysis of marginal cost pricing nor a comprehensive overview of the impacts of marginal cost pricing on industrial energy source selection. It represents a modest attempt to deal with some of the issues involved in marginal cost pricing of electricity, fossil fuels, and industrial process steam. As described here, a number of simplifying assumptions were made to carry out the comparisons, and not all variables involved in estimating marginal industrial steam costs were considered.

Actual 1980 data from public utility files were collected for two utilities to estimate the hypothetical marginal costs of electricity. The selection of

the two utilities was based on the following guidelines: 1) a significant amount of industrial electricity use; 2) location in regulatory jurisdictions that use both original (embedded) and current (replacement) cost in rate proceedings; 3) diversity in terms of geographic locations; and 4) availability of necessary data on a timely basis. The hypothetical marginal costs of electricity for the two utilities were estimated from existing electric rates and the ratio of current (replacement) cost to historical (embedded) cost. The basic procedure employed was to duplicate the existing rate setting process but to use current (replacement) cost.[2] Four factors were adjusted: return-on-capital, depreciation, fuel costs[3], and income taxes.

For the purpose of defining the marginal costs of producing industrial steam, it was assumed that a hypothetical industrial steam user could choose among four alternative energy sources for the production of process steam: oil, natural gas, coal (either high-sulfur Eastern or low-sulfur Western subbituminous) and purchased electricity. The marginal costs of fossil fuels were defined as their unregulated market prices (1980)[4]. A new 44 MW_t (150 x 10^6 Btu/hr heat input) industrial boiler was assumed for the purposes of estimating the marginal cost per million Btu of process steam. Current annualized costs of controlling emissions generated by industrial fossil fuel combustion were included with the uncontrolled boiler and fuel costs. Defining marginal costs of industrial steam in this manner is an attempt to estimate the social value of scarce energy resources and clean air.

The economic feasibility of each of these industrial boiler energy sources (oil, natural gas, coal, and electricity) was examined under the following conditions:

---

[2]It should be recognized that this procedure will likely result in electricity costs which are different than the cost of electricity that would be generated from a newly installed power plant meeting current environmental regulations.

[3]Fuel costs were not available for one utility and could not be escalated.

[4]Because of limitations of the study, location-specific fossil fuel prices were not compiled.

- Existing 1980 electricity prices of two utility companies to industrial consumers, a new 44 MW_t industrial boiler, and three levels of emissions controls for the fossil fuel-fired boilers; and

- Hypothetical industrial electricity prices for two utility companies that reflect marginal cost pricing, a new 44 MW_t industrial boiler, and three levels of emissions controls for the fossil fuel-fired boilers.

Conclusions

For the case of marginal cost pricing of all energy sources, it was found that electricity would not be competitive with fossil fuels as an industrial boiler energy source at any level of emissions control for the fossil fuel boilers. This is expected since the overall efficiency of using electricity as an industrial boiler energy source is less than half that obtained by directly firing industrial boilers with fossil fuels. It was found that use of electricity may be economically feasible for a hypothetical industrial user of electricity given actual 1980 electricity rates of one utility, fossil fuel alternatives limited to imported oil or coal, and intermediate or stringent emission controls. Given the actual 1980 rates of the second utility, however, electricity was not found to be competitive with any fossil fuel alternative under any level of emissions control.

Since this study was a "quick look" overview of the relative economics of fossil fuel combustion and electricity given hypothetical scenarios and only considered two utilities, one boiler size, and one fuel price for each of the fossil fuels, additional research may be useful. The annualized costs of various sizes of electric boilers (e.g., less than 10 MW_t) used for peaking purposes may compare more favorably with costs of steam generated with fossil fuels. Lack of data precluded examination of this alternative in this study. A site-specific analysis (considering boiler size, utilization factors, and energy prices) may identify realistic opportunities for using electricity for steam generation.

SECTION 2

ESTIMATIONS OF MARGINAL COSTS OF ELECTRICITY AND THE USER COSTS OF INDUSTRIAL STEAM GENERATION

Estimates are presented in this section of the marginal costs of electricity from the two utilities studied and the marginal costs of steam generation from four fossil fuels under three levels of emissions controls. The marginal cost of electricity is defined here to be the price that just recovers the current market value (1980 dollars) of both plant and equipment and fuel currently used to generate electricity. It may be estimated from the ratio of current costs (100 percent replacement of existing plant and equipment) to original or actual costs. Estimates are made under the assumption of increasing demand for electricity. The marginal cost of industrial steam generation is defined as the annualized costs of owning and operating a new boiler and emission control equipment installed in today's regulatory environment.

Marginal cost pricing of electricity involves the resolution of difficult conceptual issues. Briefly stated, marginal cost pricing of electricity means that electricity rates are set at levels reflecting the social costs of the capital and fuel used to generate that electricity. If existing air and water quality standards are being met by electric power generating plants, and if all inputs are valued at current costs, then the marginal costs of electricity generation reflect the social value of resources used in the production of electricity. It is important to emphasize that marginal cost pricing of electricity means that present users should pay the social costs of generating electricity from existing plant and equipment and existing fuel mixes.[5] Many electric utility rate reform

[5] It should be recognized that the procedure used in this study yields cost estimates that are likely to be different than the costs which would result from putting a newly installed power plant meeting current environmental regulations on line.

issues have centered around the use of rates that more accurately reflect the marginal costs of electricity. Consequently, estimation of the social costs of electricity under marginal cost pricing will indicate the probable effect of rate reform on the economic feasibility of using utility electricity as a boiler energy source.

In order to compare existing, regulated rates for industrial electricity with the hypothetical marginal costs of that electricity, actual 1979 regulated rates of two utilities were adjusted to reflect current costs. The basic procedure used here was to duplicate the existing rate setting process but to use current (replacement) cost of plant and equipment instead of the original (embedded) cost of plant and equipment. Four factors used in the rate setting process were adjusted: the return-on-capital, depreciation, fuel costs, and income taxes. The procedures used in making these adjustments are explained in greater detail in the next subsection.

Estimates of the marginal costs of industrial steam generation were constrained by the need to compile annualized costs for comparable boiler sizes and comparable control equipment for each of four fossil fuels under three levels of emissions control. For example, the annualized costs per 10^6 Btu of steam generated with residual oil under each control level had to be comparable with the annualized costs per 10^6 Btu of steam generated with high-sulfur Eastern coal under similar control levels. Thus, the selection of a hypothetical fossil fuel-fired boiler was limited to cases for which data were available. Fairly complete data were available for 44 MW_t (150 x 10^6 Btu/hr.) boilers fired by natural gas, oil, and coal for three levels of emissions controls. The annualized costs of generating steam for each of these fossil fuel alternatives are presented in the second subsection.

ESTIMATIONS OF MARGINAL COSTS OF ELECTRICITY

Estimation of the Marginal Costs of Electricity from Utility A

Return-on-Invested Capital--

Initially, the capitalization of the utility had to be revised to

reflect the likely distribution among long-term debt, preferred stock, and equity, given that equity is valued at replacement cost. After this revision, it was necessary to adjust the rate of return to each major capitalization component: equity, long-term debt, and preferred stock.

With respect to equity, the nominal return to common equity allowed by the Public Utility Commission that regulates Utility A is 15.0 percent (1980). Price/earnings ratios in manufacturing and transportation industries range from 9.0 to 12.5 percent, indicating that current required returns range from 11.0 to 8.0 percent (1980). (The required return is the inverse of the P/E ratio.) Because of the lower risks associated with investment in electrical utilities, the lower bound, 8.0 percent, was selected as the appropriate current required return on equity. This current required return on equity is a real rate and is equivalent to a nominal rate of return on equity of 16 to 18 percent, assuming inflation in the 8 to 10 percent range.

With respect to the cost of long-term debt and the required return on preferred stock, the current cost of capital, as reflected by current bond rates, is significantly higher than the rates established under regulation. Although the average rate for long-term Utility A debt is 7.46 percent, current bond rates are on the order of 12.0 percent. For similar reasons, the allowed 8.23 percent rate for Utility A's preferred stock was adjusted upward to 12.5 percent.

Taking the weighted average of the costs of the three components produces a 9.15 percent return on invested capital (ROI) on a current cost basis. The average ROI allowed under regulation for this utility is 10.55 percent (see Table 1).

Once the ROI is calculated in terms of current costs, it can be multiplied by the rate base to determine the current return. However, the revenue requirement under regulation is based on the investment of the firm valued at <u>original</u> capital cost less accumulated depreciation. The <u>current</u>

TABLE 1. REVISED CAPITALIZATION, CURRENT BASIS, UTILITY A

Component	Amount	Percent of Capital Structure (Wt.)	Cost	Weighted Cost
Long-Term Debt	$1,206,269,500	23.95%	12.0%	2.87%
Preferred Stock	217,012,830	4.31%	12.5%	0.54%
Common Equity	3,614,264,700	71.75%	8.0%	5.74%
				9.15%
Allowed Return on Total Invested Capital under Regulation				10.55%

cost of electricity faced by society is based on the current cost of capital equipment. Using current capital cost estimates for plant and land (supplied by Utility A) to calculate the rate base in terms of current costs, the cost of capital was determined to be $132,643,470 greater than that allowed in the regulatory proceeding (see Table 2).

Depreciation Costs--

Based on the Public Utility Commission approved depreciation rate of 3.605 percent per year, valuing the rate base at current costs would increase depreciation costs by $66,130,408 (see Table 3).

Fuel Costs--

Utility A obtains a portion of its fuel at lower than current costs because of its long-term natural gas contracts. In order to estimate the fuel costs at current price levels, the highest cost paid by this utility was applied to its total value fuel requirement.[6] The estimated increase in the cost of fuel is $247,007,178 (see Table 4).

Income Taxes--

To determine the increase in income taxes brought about by current cost valuation, the adjusted taxable income (increased returns minus increased interest payments) must be calculated and then multiplied by the effective tax rate.

As shown in Part I of Table 5, an effective income tax rate of 44.94 percent was calculated using the capitalization data provided by the Public Utility Commission. The effective tax rate was multiplied by the calculated increase in adjusted taxable income (Part II, Table 5) to determine the net increase in taxes, $34,998,748.

[6]This is still much lower than the average cost of gas for residential heating. (See discussion of retail residential gas prices on page 16.)

TABLE 2. DETERMINATION OF THE CURRENT VALUATION OF INVESTMENT, UTILITY A

	Component	Value	Source
a.	Original Cost Rate Base	$2,514,633,000	
b.	Net Original Cost of Plant	2,170,380,000	
c.	Current Cost of Plant*	4,638,600,000	
d.	Current Cost of Land	54,694,000	
e.	Total Current Cost	4,693,294,000	(c+d)
f.	Adjusted Current Rate Base	4,349,041,000	e-(a-b)
g.	Allowed Rate of Return (%)	10.55%	
h.	Allowed Return ($)	$ 265,293,782	(g x a)
i.	Current Rate of Return (Equity @ 8%) (%)	9.15%	Table 1
j.	Current Return ($)	$ 397,937,252	(i x f)
k.	Increase in the Cost of Capital	+$ 132,643,470	(j-h)

*It is assumed that emissions control costs are included in current costs.

Source: These are 1979 data that were obtained from the Public Utility Commission that regulates Utility A.

TABLE 3. DETERMINATION OF DEPRECIATION COSTS ON A CURRENT BASIS, UTILITY A

	Factor	Value	Source
a.	Approved Depreciation Rate	3.605%	
b.	Original Cost Rate Base	$2,514,633,000	Table 2
c.	Current Cost Rate Base	4,349,041,000	Table 2
d.	Depreciation Costs, Original Cost Rate Base	90,652,520	(a x b)
e.	Depreciation Costs, Current Cost Rate Base	156,782,928	(a x c)
f.	Increase in Depreciation Costs	66,130,408	(e - d)

Source: Public Utility Commission that regulates Utility A.

TABLE 4. CURRENT COSTS OF FUEL, UTILITY A

	Item	Value	Source
a.	Cost/10^6 BTU, Gas Supplier No. 1	$ 0.9227	
b.	Cost/10^5 BTU, Gas Supplier No. 2	2.246	
c.	Volume, Gas Supplier No. 1	186,660,000 M BTU	
d.	Fuel Cost, Supplier No. 1 @ $0.9227	$172,231,182	(a x c)
e.	Fuel Cost*, Supplier No. 1 @ $2.246	419,238,360	(b x c)
f.	Increase in Fuel Cost, Current Costs	247,007,178	(e - d)

* Price of fuel provided by Supplier No. 1 is escalated to reflect 1979 contract gas prices to this utility.

Source: Public Utility Commission that regulates Utility A.

TABLE 5. DETERMINATION OF THE INCREASE IN INCOME TAXES, CURRENT COST BASIS, UTILITY A

Item	Value	Source
I. To Determine the Tax Rate:		
a. Allowed Return to Common Equity	$143,371,800	(38.01%) x ($2,514,633,000) x (15.00%)*
b. Allowed Return to Preferred Stock	17,860,156	(8.63%) x ($2,514,633,000) x (8.23%)*
c. Accumulated Deferred Investment Tax Credit	14,087,100	(5.31%) x ($2,514,633,000) x (10.55%)*
d. After Tax Income	175,319,057	(a+b+c)
e. Taxes+	143,076,000	
f. Tax Rate	44.94%	(e) ÷ (d+e)
II. To Determine Increase in Income Taxes:		
g. Increased Return	$132,643,470	Table 2
h. Increased Interest Payments	54,764,635	(12.0% - 7.46%) x ($1,206,269,500)‡
i. Change in Taxable Income	77,878,835	(g - h)
j. Change in Taxes	34,998,748	(f x i)

*(% of Capital Structure) x (Total Invested Capital) x (Component Percentage Costs).

+Public Utility Commission that regulates Utility A.

‡(Average Cost of Debt - Current Cost of Debt) x (Long-Term Debt). See Table 1.

The effects of current cost valuation of Utility A's plant and equipment and natural gas contracts are summarized in Table 6. In summary, the net understatement of total current costs via regulation is on the order of $480,779,804 or 59.8 percent of total allowed costs. In other words, rates set equal to current costs would be approximately 1.59 times the rates set by the Public Utility Commission that regulates this utility. (This approximation is subject to the assumption that all users were charged their proportionate share of allowed costs.) Thus, the marginal cost of electricity generated by Utility A is approximately 60 percent greater than the regulated cost of that electricity.

Estimation of the Marginal Costs of Electricity from Utility B

In a manner directly analogous to that described previously, the costs faced by Utility B were adjusted to reflect current costs on a 100 percent replacement basis. It was not possible to determine fuel prices paid by Utility B because of lack of data. Consequently, this factor was not adjusted.

As summarized in Table 7, total current costs would exceed allowed total costs by 62.5 percent for Utility B. The percentage would likely be higher if fuel cost adjustments were made.

ESTIMATIONS OF THE USER COSTS OF ON-SITE INDUSTRIAL STEAM GENERATION

Three fossil fuels and three levels of emissions control were assumed for the purposes of estimating the marginal costs of producing industrial steam in a new, hypothetical 44 MW_t (150 x 10^6 Btu/hr) industrial boiler. A 44 MW_t boiler was assumed because the necessary cost data were readily available. (See the sources to Table B-1 of the Appendix). A load factor of 55 percent or 4,818 hours per year was assumed for both gas-fired and oil-fired boilers and a load factor of 60 percent or 5,256 hours per year was assumed for both coal-fired boilers. Annualized costs[7] for each of these new boilers were estimated. Emission control cost data were collected for two levels of control:

[7]Including fuel, O&M, plant overhead, and capital-related costs.

TABLE 6. ADJUSTED COST OF SERVICE, CURRENT COST BASIS, UTILITY A

	Item	Value	Source
a.	Increase in Return on Capital	$132,643,470	Table 2
b.	Increase in Depreciation Costs	66,130,408	Table 3
c.	Increase in Fuel Costs	247,007,178	Table 4
d.	Increase in Income Taxes	34,998,748	Table 5
e.	Total Increase	480,779,804	(a+b+c+d)
f.	Allowed Cost of Service*	803,561,000	
g.	Total Costs of Service, Current Costs	1,284,340,804	(e+f)
h.	Percentage Increase	59.83%	$\frac{g-f}{f} \times 100$

*Public Utility Commission that regulates Utility A.

TABLE 7. ADJUSTED COST OF SERVICE, CURRENT COST BASIS, UTILITY B

Item	Value
a. Increase in Return on Capital	$ 402,195,890
b. Increase in Depreciation Costs	220,196,300
c. Increase in Fuel Costs	Data Not Available
d. Increase in Income Taxes	161,067,510
e. Total Increase	783,459,700
f. Allowed Operating Revenues	1,254,449,000
g. Total Costs of Service, Current Costs	2,037,908,700
h. Percentage Increase	62.5%

Source: Calculated from 1980 data obtained from the Public Utility Commission that regulates Utility B.

intermediate and stringent. Therefore, costs are provided for a boiler and controls for the following cases: no controls, intermediate controls, and stringent controls. The stringent level of control is defined to be a technology-forcing level and is the most vigorous control that might be considered from an engineering perspective. The intermediate control level defined a level of control for each pollutant that has been commercially demonstrated and is reasonably cost-effective. It is not a recommendation for the kinds of controls that should be applied. (Emissions for each control level are defined in Table A-1 of the Appendix.)

Industrial boiler fuel prices were selected to reflect market prices. This was done for the purposes of estimating the hypothetical annualized costs of steam in the absence of regulation of fuel prices. As of November, 1979, the average price of natural gas sold directly to industrial users by pipeline companies was $2.01 per thousand cubic feet. However, given the assumption that the most desirable use of natural gas is for residential heating, a retail residential gas price of $3.49 per thousand cubic feet (November, 1979) was selected as the appropriate gas price. This price may also be taken as a reflection of unregulated market prices. In January, 1980, natural gas purchased from Canadian and other foreign sources by interstate pipeline companies averaged $3.46 per thousand cubic feet (U.S. Department of Energy, May 1980, p. 85).

Two oil prices were used in the analysis: one to reflect domestic oil prices and one to reflect imported oil prices. High-sulfur residual oil retail prices averaged $21.98 a barrel in January, 1980 (U.S. Department of Energy, May 1980, p. 83). Imported oil averaged $32.40 a barrel in February, 1980 (U.S. Department of Energy, May 1980, p. 77).

A coal price of $42.00 per ton was selected as being representative of the average market price of industrial coal in 1980 (Coal Outlook, 1980, pp. 4-5).

The total annualized costs of steam (in dollars per 10^6 Btu) were then calculated for each fuel under three control levels (no controls, intermediate controls, and stringent controls). These costs are shown in Table 8.

TABLE 8. ANNUALIZED COSTS OF PRODUCING STEAM GIVEN A 44 MW_t BOILER*, FOUR BOILER FUELS, AND THREE EMISSIONS CONTROL LEVELS (MAY, 1980 DOLLARS)

Fuel	Fuel Price+	Annualized Steam Costs, $/10^6 Btu		
		No Controls	Intermediate Controls	Stringent Controls
Natural Gas	$ 3.49.mcf	$5.73	$5.74	$6.06
3.0% Sulfur Residual Oil	$21.98/bbl	5.89	7.40	8.06
	$32.40/bbl	7.84	9.34	10.01
3.5% Sulfur Eastern Coal	$42.00/ton	6.81	8.77	9.54
0.6% Sulfur Western Subbituminous Coal	$42.00/ton	7.81	9.28	9.89

*The load factor for both the gas- and oil-fired boilers is 55 percent or 4,818 hours per year. The load factor for both coal-fired boilers is 60 percent or 5,256 hours per year. For purposes of simplicity, it is assumed that loads are evenly distributed throughout the year.

+All fuel prices are based on 1979 and 1980 unregulated market prices. See U.S. Department of Energy, May 1980. Fuel prices paid by the hypothetical industrial user are probably higher in all cases than those paid by the two utilities. It was not feasible to make site-specific analyses given the level of effort specified in the project scope of work.

Source: Calculated on the basis of boiler characteristics, control levels, detailed cost data, and sources which are provided in Appendix B.

SECTION 3

ANALYSIS OF IMPACTS OF ALTERNATIVE UTILITY RATE STRUCTURES ON INDUSTRIAL SELECTION OF A BOILER ENERGY SOURCE

The purpose of this section is to examine the impacts of alternative utility rate structures on industrial energy source choices. The objective of this analysis is to illustrate the impact of marginal cost pricing of electricity on the competitiveness of electricity as an energy source for industrial boilers.

In the first subsection, the marginal costs of fossil fuel generation of steam (presented in Table 8) are compared with the costs of steam generation using electricity. Existing regulated rates charged by Utility A and Utility B are used in this first comparison. A similar comparison is made in the second section using the marginal costs of Utility A and Utility B electricity. The marginal costs of on-site fossil fuel generation of steam are used in both comparisons and are taken as the costs of generating steam in new industrial boilers.

THE ECONOMICS OF FUEL CHOICE USING EXISTING ELECTRICITY RATES

For the purposes of this analysis it was assumed that an industrial customer wishing to construct and operate a new 44 MW_t electric boiler would consume 211,992,000 KWH of electricity annually (assuming a 55% utilization factor) with an assumed peak demand of 44,000 KW. It was also assumed that the 211,992,000 KWH would be used uniformly over the year at the rate of 17,666,000 KWH per month.

Table 9 presents the existing rates for a large industrial user within Utility A's service area. These rates reflect capacity and KWH charges with the latter broken down into a basic KWH charge and a fuel cost factor. Application of these rates to the hypothetical industrial customer with a

TABLE 9. UTILITY A RATES FOR AN INDUSTRIAL USER

Capacity Charge/KW/mo for 225,000 KW:	**$4.6424/KW**
KWH Charges	
Basic for 164,250,000 KWH:	**$0.00042/KWH**
Fuel Cost Factor/KWH:	**$0.023114/KWH**

Source: These rates were obtained from the Public Utility Commission that regulates Utility A.

TABLE 10. ANNUAL ELECTRICITY COST OF A 44 MW_t ELECTRIC BOILER FOR 4,818 HOURS (PEAK DEMAND = 44,000 KW), UTILITY A (1980 DOLLARS)

Capacity Charge	$2,451,187.20
KWH Charges:	
Basic	89,036.64
Fuel Costs	4,899,983.09
Total	7,440,206.93
Total KWH Consumed	211,992,000 KWH
Average Cost Per KWH	$ 0.0351

44,000 KW maximum demand and uniform monthly consumption of 17,666,000 KWH results in the electricity costs shown in Table 10.

Table 11 presents the existing electricity rates for industrial users for the Utility B service area. Utility B has two general industrial rates, Primary Distribution (P.D.) and High Tension (H.T.). The rates consist of three charges: customer, capacity, and energy. Table 12 shows the cost of the electricity to an industrial user in the Utility B service area under both P.D. and H.T. rates. As shown, the resulting cost per KWH is $0.0282 for the P.D. rates and $0.0263 for the H.T. rates.

In addition to the electricity cost of generating steam by electric boilers, the industrial customer would incur annual O&M and annualized capital-related costs associated with operating a new electric boiler. As estimated (see Table B-5 in Appendix), these costs would range from $54,000 - $280,000 for the 44 MW_t boiler, depending on how much of the necessary equipment to receive and distribute the electricity was already in place at the plant.

Table 13 combines the annualized capital costs and electricity costs to obtain the total annualized cost of a 44 MW_t electric boiler. These costs are also expressed as dollars per 10^6 Btu of steam using rates for both Utility A and Utility B. As shown in Table 13, the cost per 10^6 Btu for the user of Utility A electricity ranges from $10.37 to $10.68. For the user of Utility B electricity, the cost per 10^6 Btu ranges from $7.80 to $8.65. The mid-point of the range for Utility A is $10.53/$10^6$ Btu; and for Utility B, the mid-point is $8.23/$10^6$ Btu.

Table 14 compares cost of steam produced with electricity to the cost of steam produced from natural gas (at $3.49/mcf), residual fuel oil ($21.98/bbl), imported oil ($32.40/bbl), high sulfur Eastern coal (at $42/ton), and low sulfur Western subbituminous coal (at $42/ton). Costs are shown for three levels of emissions controls. Electricity costs are shown for both Utility A and Utility B. The mid-points of both costs are used as the basis of comparison.

TABLE 11. UTILITY B RATES FOR LARGE INDUSTRIAL USERS

Primary Distribution (P.D.)*	
Monthly Customer Charge:	$75.00
Capacity Charge (for peak demand):	$4.50/KW/Month for the first 50 KW 3.07/KW/Month for KW above 50 KW
Energy Charge:	$0.0409/KWH each month for the first 150 KWH 0.0306/KWH each month for the next 150 KWH 0.0205/KWH each month for all additional KWH
High Tension (H.T.)*,+	
Monthly Customer Charge:	$71.50
Capacity Charge (for peak demand):	$4.46/KW/Month for the first 50 KW 2.98/KW/Month for KW above 50 KW
Energy Charge:	$0.0357/KWH each month for the first 150 KWH 0.0272/KWH each month for the next 150 KWH 0.0189/KWH each month for all additional KWH

*For both P.D. and H.T., the customer owns and installs the receiving equipment.

+There is a discount for high voltage under the H.T. Rate.

Source: These rates were obtained from the Public Utility Commission that regulates Utility B.

TABLE 12. ANNUAL ELECTRICITY COST OF A 44 MW_t ELECTRIC BOILER FOR 4,818 HOURS (PEAK DEMAND = 44,000 KW), UTILITY B (1980 DOLLARS)

	P.D. Rate	H.T. Rate
Customer Charge	$ 900.00	$ 858.00
Capacity Charge	1,621,818.00	1,574,328.00
Energy Charge	4,345,890.96	4,006,694.04
Total	5,968,608.96	5,581,880.04
Total KWH Consumed	211,992,000 KWH	211,992,000 KWH
Cost Per KWH	$ 0.0282	$ 0.0263

TABLE 13. TOTAL ANNUALIZED COSTS OF PRODUCING STEAM FROM A 44 MW_t ELECTRIC BOILER* GIVEN EXISTING ELECTRICITY RATES (1980 DOLLARS)

Utility/Rates	Electricity Cost	Annualized Capital Cost+	Total Annualized Costs	Cost $/10^6 Btu
Utility A	$7,440,207	$ 54,000	$7,494,207	$10.37
Utility A	7,440,207	280,000	7,720,207	10.68
Utility B/P.D.	5,968,609	54,000	6,022,609	8.33
Utility B/P.D.	5,968,609	280,000	6,248,609	8.65
Utility B/H.T.	5,581,880	54,000	5,635,880	7.80
Utility B/H.T	5,581,880	280,000	5,861,880	8.11

Range of Costs (in $/10^6 Btu)

Utility A $10.37 - $10.68
Utility B 7.80 - 8.65

*The load factor is 55 percent or 4,818 hours per year; peak demand is 44,000 KW.

+Data for electric boiler capital costs are provided in Table B-5 of the Appendix. Annualized Capital costs vary according to whether receiving equipment is already in place at an industrial site.

TABLE 14. COSTS ($/10^6 Btu) OF PRODUCING STEAM FROM FOSSIL FUELS AND ELECTRICITY USING EXISTING ELECTRICITY RATES (1980 DOLLARS) OF UTILITY A AND UTILITY B

Fuel Type*	Level of Emissions Control for Fossil Fuel-Fired Boilers		
	None	Intermediate	Stringent
Natural Gas	$5.73	$5.74	$6.06
Residual Oil (at $21.98/bbl)	5.89	7.40	8.06
Imported Oil (at $32.40/bbl)	7.84	9.34	10.01
High Sulfur Eastern Coal (at $42/ton)	6.81	8.77	9.54
Low Sulfur Western Subbituminous (at $42/ton)	7.81	9.28	9.89
Electricity			
Utility A			
Mid-point of Range (Range)	$10.53 (10.37-10.68)	$10.53 (10.37-10.68)	$10.53 (10.37-10.68)
Utility B			
Mid-point of Range (Range)	8.23 (7.80-8.65)	8.23 (7.80-8.65)	8.23 (7.80-8.65)

*The load factor for the gas-fired and oil-fired boilers and for the electric boiler is 55 percent or 4,818 hours per year. The load factors for both coal-fired boilers is 60 percent or 5,256 hours per year.

The cases where electricity might be economically attractive as a boiler energy source for producing steam under present regulated rates of both utilities are summarized in Table 15. Given existing regulated rates of Utility B and no emission controls on industrial boilers, use of electricity for producing steam would not be economically feasible. However, given either intermediate or stringent levels of emissions controls, the cost of producing industrial steam via electricity is lower than the costs of producing steam with either imported oil, high sulfur Eastern coal, or low sulfur subbituminous Western coal. Given existing rates of Utility A, however, use of electricity as a boiler energy source is not an economically viable option, irrespective of the level of emissions control on the industrial boiler. These conclusions should not be extrapolated to other situations. They are valid for the cases evaluated (i.e., one boiler size, estimated fuel prices, existing electricity rates for utilities A & B, etc.).

THE ECONOMICS OF FUEL CHOICE USING ELECTRICITY RATES BASED UPON MARGINAL COST PRICING

In Section 2, the degree to which each utility's rate base would have to be increased to recover current costs was estimated. For Utility A it was determined that the rate base would have to be increased by 59.8 percent to recover current costs. For Utility B, on the other hand, the rate base would have to be increased by 62.5 percent. Assuming that demand continues to increase in both service areas and that all users would be charged their proportionate share of allowed costs, multiplication of the present rates by 1.598 for Utility A and 1.625 for Utility B produces rates that reflect the approximate marginal cost of electricity in each utility's service area.

It should be noted that the analysis is based upon the assumption of increasing demand for electricity. This means that the industrial user would cause the utility serving that user to install additional generating

TABLE 15. CASES WHERE ELECTRICITY (PRESENT RATE STRUCTURE) MAY BE ECONOMICALLY ATTRACTIVE FOR THE HYPOTHETICAL BOILER STUDIED

	Level of Control		
	None	Intermediate	Stringent
Utility A	None	None	None
Utility B	None	Imported Oil High Sulfur Eastern Coal Low Sulfur Western Subbituminous Coal	Imported Oil High Sulfur Eastern Coal Low Sulfur Western Subbituminous Coal

capacity.[8] On the other hand, if the utility has excess capacity in anticipation of increased demand, but demand increases less rapidly than expected, the relevant marginal cost would be different.

Table 16 presents the annualized costs of producing steam from a 44 MW_t electric boiler assuming that the present electric rates are adjusted to recover the current cost rate base. The adjusted costs were determined by multiplying the electricity costs in Table 13 by 1.598 for Utility A and by 1.625 for Utility B. The resulting costs per 10^6 Btu of steam are $16.53 to $16.84 for Utility A and $12.63 to $13.81 for Utility B.

Table 17 presents the costs of producing steam using four fossil fuels and electricity rates based on marginal cost pricing. As indicated by the cost figures in Table 17, electricity priced at marginal cost is not competitive as a boiler energy source for industrial steam under any alternative. Thus, if all energy sources for producing steam were priced at marginal costs, electricity would not be competitive with fossil fuels for the two cases studied. This is expected since the efficiency of generating steam from fossil fuels is about twice as great as generating electricity from fossil fuel combustion and then raising steam using the electricity.

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[8] The reader should remember the procedure for calculating marginal costs for electricity will likely result in costs which are different than the cost of electricity that would be generated from a newly-installed power plant.

TABLE 16. TOTAL ANNUALIZED COSTS AND COSTS ($/10^6 Btu) OF PRODUCING STEAM FROM A 44 MW_t ELECTRIC BOILER* GIVEN ELECTRICITY RATES THAT REFLECT MARGINAL COST PRICING (1980 DOLLARS)

Utility/Rates	Fuel Cost	Capital Cost +	Total Annualized Cost	Cost/ 10^6 Btu
Utility A	$11,889,451	$ 54,000	$11,943,451	$16.53
Utility A	11,889,451	280,000	12,169,451	16.84
Utility B/P.D.	9,698,990	54,000	9,752,990	13.50
Utility B/P.D.	9,698,990	280,000	9,978,990	13.81
Utility B/H.T.	9,070,555	54,000	9,124,555	12.63
Utility B/H.T.	9,070,555	280,000	9,350,555	12.94

Range of Costs (in $/$10^6$ Btu)

Utility A $16.53 - $16.84
Utility B 12.63 - 13.81‡

* The load factor is 55 percent or 4,818 hours per year; peak demand is 44,000 KW.

\+ Data for electric boiler capital costs are provided in Table B-5 of the Appendix. Annualized capital costs vary according to whether receiving equipment is already in place at an industrial site.

‡ Utility B's electric rates do not contain a fuel cost escalation component. As pointed out in Table 7, fuel cost data for Utility B were not available to the authors at the time this report was prepared.

TABLE 17. COSTS ($/10^6 Btu) OF PRODUCING STEAM FROM FOSSIL FUELS AND ELECTRICITY GIVEN ELECTRICITY RATES OF UTILITY A AND UTILITY B THAT REFLECT MARGINAL COST PRICING (1980 DOLLARS)

Fuel Type*	Level of Emissions Control For Fossil-Fuel-Fired Boilers		
	None	Intermediate	Stringent
Natural Gas	$5.73	$ 5.74	$6.06
Residual Oil	5.89	7.40	8.06
Imported Oil	7.84	9.34	10.01
High Sulfur Eastern Coal	6.81	8.77	9.54
Low Sulfur Western Subbituminous	7.81	9.28	9.89
Electricity			
Utility A			
Mid-point of Range	$16.69	$16.69	$16.69
(Range)	(16.53-16.84)	(16.53-16.84)	(16.53-16.84)
Utility B			
Mid-point of Range	13.22	13.22	13.22
(Range)	(12.63-13.81)	(12.63-13.81)	(12.63-13.81)

* Due to the use of small amounts of electricity in the fossil fuel alternatives, the costs should increase slightly. For purposes of simplification, however, these are ignored here. The load factor for the gas-fired and oil-fired boilers and for the electric boiler is 55 percent or 4,818 hours per year. The load factors for both coal-fired boilers is 60 percent or 5,256 hours per year.

LIMITATIONS OF THIS STUDY

This study is neither a definitive analysis of marginal cost pricing techniques nor a comprehensive overview of the impacts of marginal cost pricing on industrial energy sources.[9] This study was a modest attempt to deal with some of the issues involved in marginal cost pricing of electricity, fossil fuels, and industrial process steam. The number of variables that need to be taken into account in estimating marginal industrial steam costs is large. Only a few of these were taken into account in this evaluation. A second purpose of this study was to compare the impacts of both marginal cost pricing of all energy sources and increasingly stringent emission controls for industrial boilers on the selection of an industrial boiler energy source. Again, a number of simplifying assumptions had to be made in order to carry out these comparisons.

The results of this study are not applicable to all situations where selection of an industrial boiler energy source has to be made. These results are valid only for the cases described and for the assumptions made. For example, location-specific industrial fossil fuel prices were not estimated in the analysis. The modest level of effort of this study precluded undertaking the level of data collection required for a location-specific evaluation. A location-specific evaluation of the impacts of marginal cost pricing might very well lead to different conclusions.

[9] The reader who is interested in marginal cost pricing of electricity should consult the multi-volume Electric Utility Rate Design Study.

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GLOSSARY

economically efficient prices: Prices which accurately reflect the costs of the goods sold. This involves setting prices equal to marginal costs. When price equals marginal cost and when total costs are minimized, the quantity of goods produced should exactly match consumers' demands for the good or service produced.

marginal cost: In general, marginal cost is equal to the increase in total cost that is attributable to producing one additional unit or output of a particular good holding all of a firm's other outputs constant. In this study, the marginal cost of electricity is defined to be the price that just recovers the current market value (1980 dollars) of both plant and equipment and fuel currently used to generate electricity. In this study, the marginal cost of industrial steam generation is taken as the annualized cost of steam from a new 44 MW_t boiler

marginal cost pricing: Pricing <u>all</u> units of output at a level equal to the marginal cost of the <u>last</u> unit of output produced.

APPENDIX A

EMISSIONS CONTROL LEVELS FOR INDUSTRIAL BOILERS

Three levels of emissions controls for industrial boilers were selected for this study: no controls, intermediate controls, and stringent controls. Allowable emissions under intermediate and stringent controls are provided in Table A-1. These are the control levels used in estimating costs for the 44 MW_t industrial boilers in this study only and are not necessarily indicative of regulatory requirements.

TABLE A-1. APPROXIMATE EMISSION RATES FOR THREE LEVELS OF EMISSIONS CONTROLS

Pollutant/Fuel	No Controls	Intermediate Controls	Stringent Controls
NO_x (lb/10^6 Btu)			
Natural Gas	0.23	0.20	0.03
Residual Oil	0.40	0.30	0.04
Coal	0.70	0.60	0.07
SO_2 (Percent Removal)			
Natural Gas	--	--	--
Oil	--	75.00	90.00
Coal	--	75.00	90.00
Particulates (lb/10^6 Btu)			
Natural Gas	--	--	--
Oil	.23	0.10	0.03
Coal	1.00+	0.10	0.03

APPENDIX B

OPERATING CHARACTERISTICS AND ANNUALIZED COSTS OF 44 MW_t INDUSTRIAL BOILERS

A hypothetical 44 megawatt (150 x 10^6 Btu/Hr) industrial boiler was selected for evaluation in this study because fairly detailed and comparable cost data are available for boilers of this size, as well as emission control equipment. These data are presented in the following five tables for each of five boiler energy sources: natural gas, residual oil, high sulfur Eastern coal, low sulfur Western subbituminous coal, and electricity. The data consist of annualized costs of uncontrolled boilers and annualized costs of two levels of control of nitrogen oxides, sulfur dioxide, and particulates. Annualized costs include annual O&M, plant overhead, raw materials, utilities, fuel, and capital investment-related costs.

TABLE B-1. OPERATING CHARACTERISTICS AND ANNUALIZED COSTS OF A 44 MW_t INDUSTRIAL BOILER FIRED WITH NATURAL GAS

Boiler[1]:	44 MW thermal input (150 x 10^6 Btu/hour) Package, water tube, 30 year life Efficiency: 87.0 percent
Load factor:	55 percent or 4,818 hours/year
Fuel rate:	150,000 cubic feet/hour
Heating value:	1,000 Btu/cubic foot
Annual fuel consumption:	722,700,000 cubic feet

	Annualized Costs		
	No Controls	Intermediate Level of Control	Stringent Level of Control
Uncontrolled boiler[2]	913,600	913,600	913,600
NO_x controls[3]	None	4,000	174,700
SO_2 controls[4]	None	None	None
Particulate controls[5]	None	None	None
Total, 1978 dollars	913,600	917,600	1,088,300
Total, 1980 dollars[6]	1,078,962	1,083,686	1,285,282
Fuel costs[7] $3.49/thousand cubic feet	2,522,223	2,522,223	2,522,223
Total annualized costs, May 1980 dollars	3,601,185	3,605,909	3,807,505
Steam costs, net thermal output, $/$10^6$ Btu	$5.73	$5.74	$6.06

[1]Boiler design parameters are from Devitt, Spaite, and Gibbs (1979), p. 99.

[2]Annualized costs of an uncontrolled boiler are reported in Devitt, Spaite, and Gibbs (1979), p. G-56. Uncontrolled boiler costs do not include boiler fuel costs.

[3]Nitrogen oxides (NO_x) control costs (stringent) are from Jones and Johnson (1979), p. A7-28, and are for Selective Catalytic Reduction (SRC) Fixed Packed Bed. Intermediate level of control costs are for combustion modifications.

[4]Gas-fired boilers do not require a sulfur dioxide (SO_2) control system.

[5]Uncontrolled particulate emissions from gas-fired boilers are considerably less than those allowed under the assumed stringent level of control. (See Table A-1.) Consequently, properly operated and maintained gas-fired units do not require particulate controls (Roeck and Dennis, 1979, p. 114).

[6]All cost data compiled from the preceding sources are reported in June, 1978. dollars. These data were inflated by 18.1 percent to reflect May, 1980, prices. The inflation rate was calculated from GNP implicit price deflators as reported in U.S. Department of Commerce (1980), p. 84.

[7]It is assumed that the socially optimal use for natural gas is for residential heating. The average retail price of natural gas sold to residential customers for heating was $3.49 per thousand cubic feet in November, 1979 (U.S. Department of Energy, March 1980).

TABLE B-2. OPERATING CHARACTERISTICS AND ANNUALIZED COSTS OF A 44 MW$_t$ INDUSTRIAL BOILER FIRED WITH RESIDUAL OIL (3.0 PERCENT SULFUR)

Boiler[1]:	44 MW thermal input (150 x 10^6 Btu/hour) Package, water tube, 30 year life Efficiency: 85.0 percent
Load factor:	55 percent or 4,818 hours/year
Fuel rate:	1,000 gallons/hour
Heating value:	149,800 Btu/gallon
Annual fuel consumption:	4,818,000 gallons or 114,715 barrels

	Annualized Costs		
	No Controls	Intermediate Level of Control	Stringent Level of Control
Uncontrolled boiler[2]	930,000	930,000	930,000
NO_x controls[3]	None	4,000	222,860
SO_2 controls[4]	None	683,000	742,000
Particulate controls[5]	None	146,631	164,227
Total, 1978 dollars	930,000	1,713,631	2,059,087
Total, 1980 dollars[6]	1,098,330	2,023,798	2,431,782
Fuel Costs			
$21.98/bbl[7]	2,521,436	2,521,436	2,521,436
$32.40/bbl[8]	3,716,766	3,716,766	3,716,766
Total annualized costs, May 1980 dollars			
$21.98/bbl	3,619,766	4,545,234	4,953,218
$32.40/bbl	4,815,096	5,740,564	6,148,548
Steam costs, net thermal output, $/$10^6$ Btu			
$21.98/bbl fuel	$5.89	$7.40	$ 8.06
$32.40/bbl fuel	$7.84	$9.34	$10.01

[1]Boiler design parameters are from Devitt, Spaite, and Gibbs (1979), p. 97.

[2]Annualized costs of an uncontrolled boiler are reported in Devitt, Spaite, and Gibbs (1979), p. G-29. Uncontrolled boiler costs do not include boiler fuel costs.

[3]Nitrogen oxides (NO_x) control costs (stringent) are from Jones and Johnson (1979), p. A7-22, and are for parallel flow Selective Catalytic Reduction (SCR) at 90 percent NOx removal. Intermediate level of control costs are for combustion modifications.

[4]Sulfur dioxides (SO_2) control cost data are reported in Dickerman and Johnson (1979), p. 4-43. Intermediate data are for 75 percent SO_2 removal, and stringent data are for 90 percent SO_2 removal.

[5]Cost data are for an electrostatic precipitator with 75 percent removal (intermediate level of control). Data reported in Roeck and Dennis (1979), pp. 187-189. Actual cost data for an ESP at the stringent level of control were not available to the authors. The figure reported here was estimated.

TABLE B-2. (Continued)

[6]All cost data compiled from the preceeding sources are reported in June, 1978, dollars. These data were inflated by 18.1 percent to reflect May, 1980, prices. The inflation rate was calculated from GNP implicit price deflators as reported in U.S. Department of Commerce (1980), p. 84.

[7]U.S. Department of Energy, (May 1980), p. 83. This is the January, 1980, retail price for #6 residual oil greater than 1.0 percent sulfur.

[8]Ibid., p. 77. This price of $32.40 is the February, 1980, crude oil refiner acquisition cost for imported crude. It includes transportation costs, fees, and any other cost incurred in purchasing and shipping crude oil to the U.S.

TABLE B-3. OPERATING CHARACTERISTICS AND ANNUALIZED COSTS OF A 44 MW_t INDUSTRIAL BOILER FIRED WITH EASTERN COAL (3.5 PERCENT SULFUR)

Boiler[1]:	44 MW thermal input (150 x 10^6 Btu/hour) Field erected water-tube, spreader stoker, 45 year life Efficiency: 80.9 percent
Load factor:	60 percent or 5,256 hours/year
Fuel rate:	6.36 tons/hour
Heating value:	11,800 Btu/lb
Annual fuel consumption:	33,428 tons

	Annualized Costs		
	No Controls	Intermediate Level of Control	Stringent Level of Control
Uncontrolled boiler[2]	2,491,600	2,491,600	2,491,600
NOx controls[3]	None	4,000	291,000
SO_2 controls[4]	None	865,000	974,000
Particulate controls[5]	None	184,982	205,330
Total, 1978 dollars	2,491,600	3,545,582	3,961,930
Total, 1980 dollars[6]	2,942,580	4,187,333	4,679,039
Fuel costs[7] $42.00/ton	1,403,976	1,403,976	1,403,976
Total annualized costs, May 1980 dollars	4,346,556	5,591,309	6,083,015
Steam costs, net thermal output, $/$10^6$ Btu	$6.81	$8.77	$9.54

[1]Boiler design parameters are from Devitt, Spaite, and Gibbs (1979), p. 100.

[2]Annualized costs of an uncontrolled boiler are reported in Devitt, Spaite, and Gibbs (1979), p. G-32: Uncontrolled boiler costs do not include boiler fuel costs.

[3]Costs were assumed to be same as for the Western coal boiler (Table B-4).

[4]Sulfur dioxide (SO_2) control systems are limestone throwaway systems. These SO_2 cost data are reported in Dickerman and Johnson (1979), p. 4-43, p. B-13, and p. B-15. Intermediate control assumes 75 percent SO_2 removal, and stringent control assumes 90 percent removal.

[5]Cost data for electrostatic precipitators are reported in Roeck and Dennis (1979), p. 145 (intermediate controls) and p. 171 (stringent controls).

[6]All cost data compiled from the preceeding sources are reported in June, 1978, dollars. These data were inflated by 18.1 percent to reflect May, 1980, prices. The inflation rate was calculated from GNP implicit price deflators as reported in U.S. Department of Commerce (1980), p. 84.

[7]A delivered price of $42.00 per ton was used by Energy and Environmental Analysis, Inc., Arlington, VA, in recent forecasts of industrial coal consumption. Reported in Coal Outlook, April 7, 1980. pp. 4-5.

TABLE B-4. OPERATING CHARACTERISTICS AND ANNUALIZED COSTS OF A 44 MW_t INDUSTRIAL BOILER FIRED WITH WESTERN SUBBITUMINOUS COAL (0.6 PERCENT SULFUR)

Boiler[1]:	44 MW thermal input (150 x 10^6 Btu/hour) Field erected, water-tube, spreader stoker, 45 year life Efficiency: 81.5 percent
Load factor:	60 percent or 5,256 hours/year
Fuel rate:	7.81 tons/hour
Heating value:	9,600 Btu/lb
Annual fuel consumption:	41,050 tons

	Annualized Costs		
	No Controls	Intermediate Level of Control	Stringent Level of Control
Uncontrolled boiler[2]	2,790,000	2,790,000	2,790,000
NO_x controls[3]	None	4,000	291,000
SO_2 controls[4]	None	537,000	576,000
Particulate controls[5]	None	256,071	264,911
Total, 1978 dollars	2,790,000	3,587,071	3,921,911
Total, 1980 dollars[6]	3,294,990	4,236,331	4,631,777
Fuel costs[7] $42.00/ton	1,724,100	1,724,100	1,724,100
Total annualized costs, May 1980 dollars	5,019,090	5,960,431	6,355,877
Steam costs, net thermal output, $/$10^6$ Btu	$7.81	$9.28	$9.89

[1]Boiler design parameters are from Devitt, Spaite, and Gibbs (1979), p. 100.

[2]Total annualized costs of an uncontrolled boiler are reported in Devitt, Spaite, and Gibbs (1979), p. G-38. Uncontrolled boiler costs do not include boiler fuel costs.

[3]Nitrogen oxides (NO_x) control costs for the stringent level are from Jones and Johnson (1979), p. 1-16 and are for Selective Catalytic Reduction (SCR) at 90 percent NO_x removal. Costs for the intermediate level are for combustion modifications.

[4]Sulfur dioxide (SO_2) control systems are limestone throwaway systems. These SO_2 cost data are reported in Dickerman and Johnson (1979), p. B-33 and P. B-37. Intermediate control assumes 75 percent SO_2 removal and stringent control assumes 90 percent removal.

[5]Cost data for electrostatic precipitators are reported in Roeck and Dennis (1979), p. 145, (intermediate controls) and p. 171 (stringent controls).

[6]All cost data compiled from the preceeding sources are reported in June, 1978, dollars. These data were inflated by 18.1 percent to reflect May, 1980, prices. The inflation rate was calculated from GNP implicit price deflators as reported in U.S. Department of Commerce (1980), p. 84.

[7]A delivered price of $42.00 per ton was used by Energy and Environmental Analysis, Inc., Arlington, VA, in recent forecasts of industrial coal consumption. Reported in Coal Outlook, April 7, 1980, pp. 4-5.

TABLE B-5. OPERATING CHARACTERISTICS, CAPITAL INVESTMENT, AND ANNUALIZED COSTS OF A 44 MW_t ELECTRIC BOILER

Boiler[1]:	44 MW thermal input (150 x 10^6 Btu/hour) High voltage spray electrode, 30 year life Efficiency: 99.9 percent
Load factor:	55 percent of 4,818 hours/year
Fuel rate:	44,000 KWH
Heating value:	3,413 Btu per kilowatt
Annual electricity consumption:	211,992,000 KWH
Air emissions:	None

	Receiving Equipment Already On-Site	Receiving Equipment Installed with Boiler
Capital Investment[2]		
Equipment cost[3]	$185,000	$ 185,000
Installation (direct)	18,500[4]	925,000[5]
Total direct	203,500	1,110,000
Installation (indirect) (32%)	65,120	355,200
Performance tests	2,000	2,000
Total indirect	67,120	357,200
Total direct and indirect	270,620	1,467,200
Contingencies (20%)	54,124	293,440
Turnkey	324,744	1,760,640
Land	Not Available	Not Available
Working capital (10% of turnkey)	32,475	176,064
Total Capital Investment	357,219	1,936,704
Annualized Costs[4]		
Direct cost		
Maintenance labor (100 hours/year)	1,423	1,423
Chemicals	Not Available	Not Available
Total direct cost	-2,000	-2,000
Overhead		
Payroll (30%)	600	600
Plant (30%)	600	600
Total overhead	1,200	1,200
Capital charges		
G&A (4% of turnkey)	12,990	70,425
Capital recovery (10.61 of turnkey)	34,455	186,804
Interest on working capital	3,250	17,606
Total capital charges	50,695	274,835
Total annualized costs[6] (excluding cost of electricity)	53,895 (-54,000)	278,035 (-280,000)

TABLE B-5. (Continued)

[1]Some of this information was obtained in telephone conversations with Bob Dykes, EPA/IERL, Research Triangle Park, NC; Tom Corwin, PEDCo Environmental, Cincinnati, Ohio; and Mark O'Brian, Cam Industries, Kent, Washington. Published data on electric boiler characteristics and steam quality from electric boilers were not available during report preparation.

[2]Cost estimates for a 44 MW_t electric boiler were not available during report preparation. These annualized costs are rough "guesstimates." Given the low capital and maintenance costs of electric boilers, the possibility of large errors in these estimates will not affect the analysis. The major annualized cost component of an electric boiler is the cost of electricity. The cost of electricity is not included in this table.

[3]A purchase price of $185,000 for a 44 MWt electric boiler was supplied by Mark O'Brian of Can Industries, Kent, Washington, on June 17, 1980.

[4]Assumes that transmission lines and transformers are already in place at an industrial site.

[5]Assumes that an industrial user has to install transmission lines and transformers to supply utility electricity to an electric boiler located at the industrial site. Bob Dykes, EPA/IERL, Research Triangle Park, NC, stated that electric boiler installation costs could vary by as much as 300 percent depending on whether receiving equipment was in place at the site.

[6]Total annualized costs were estimated on the basis of procedures recommended in Devitt, Spaite, and Gibbs (1979), pp. 112-126.